Time Dependent Valuation of Energy for Developing Building Efficiency Standards

2013 Time Dependent Valuation (TDV) Data Sources and Inputs

February 2011

Energy+Environmental Economics

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Submitted to Martha Brook

California Energy Commission

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Contents Overview

This report describes data sources, calculations and results used in the 2013 Time Dependent Valuation (TDV) update for the Title 24 building standards. It reflects the TDV values included in the excel file named "2011 TDV v3 110112.xls"

Acknowledgements

We would like to acknowledge the contributions and hard work of the following individuals at the California Energy Commission for developing the production simulation model data inputs described in this report.

Angela Tanghetti, Christopher McLean

1 Background and Changes in 2013 TDV Inputs & Methodology

1.1 Principals and Purpose of TDVs

The Title 24 building standards are developed based upon the cost-effectiveness of energy efficiency measures in new buildings in California. The standards promote measures that have a positive benefit-cost ratio from a modified participant cost perspective. The Title 24 standards allow building designers to make trade-offs between energy saving measures using building simulation tools that evaluate the energy performance of proposed building designs.

Beginning with the 2005 standards update, time-dependent valuation (TDV) has been used in the cost-effectiveness calculation for Title 24. The concept behind TDV is that energy efficiency measure savings should be valued differently depending on which hours of the year the savings occur, to better reflect the actual costs of energy to consumers, to the utility system, and to society. The TDV method encourages building designers to design buildings that perform better during periods of high energy cost. Prior to 2005, the value of energy efficiency measure savings had been calculated on the basis of a "flat" source energy cost. In the 2013 TDV update, the hourly TDV factors are also correlated with the statewide typical weather files used in building simulation tools. This is important because in California hotter weather tends to be correlated with increased demand on the electrical system, increasing the cost of energy during those hours.

This report has been developed to document the methodology used to compute the 2013 TDV factors used in Title 24. The basic concepts and approach used to develop the TDV methodology are the following:

1. **Rational and Repeatable Methods**

   We have used published and public data sources for the fundamental analysis approach to developing TDV data. This allows revisions of the Standards and their underlying TDV data to be readily updated when called for by the California Energy Commission (CEC).

2. **Based on Hourly (or Monthly) Cost of Energy, Scaled to Retail Rate Levels**

   TDV is based on a series of annual hourly values for electricity cost (and monthly costs for natural gas and propane) in the typical CEC weather year. TDV values are developed for each of the sixteen climate zones, for residential and for nonresidential buildings. We have not used retail rates to value energy savings directly because rates are based on averages over time periods rather than hourly differences in the cost of generation. However, the hourly TDV values have been adjusted to be equivalent to a residential and nonresidential statewide average retail rate forecast.

3. **Seamless Integration within Title 24 Compliance Methods**

   The mechanics of TDV should be transparent to the user community and compliance methods should remain familiar and easy. TDV factors are represented in kWh/Btu or therms/Btu units, consistent with the previously used source energy approach and the 2005 and 2008 TDV updates.

4. **Climate Zone Sensitive**

   As with the weather data used for Title 24 performance calculations, which allow building designs to be climate responsive, the TDV methodology also reflects differences in costs driven by climate conditions. For example, an extreme, hot climate zone has higher, more concentrated peak energy costs than a milder, less variable climate zone.

5. **Components of TDV**

   The TDV method develops each hour's (or month's) energy valuation using a bottom-up approach. We sum together the individual components of the cost of energy and then scale up the values such that over the course of the year the values are equal the average retail price for residential and non-residential customers. The resulting electricity TDV factors vary by hour of day, day of week, and time of year. The key components of the electricity TDV factors are summarized below:

   - Marginal Cost of Electricity – *variable by hour* – The shape of the hourly marginal cost of generation is developed using the Commission's production simulation dispatch model (developed by Ventyx). The price shape from the production simulation model is then adjusted to reflect the natural gas price forecast as well as the following non-energy costs of energy: transmission & distribution costs, emissions costs, ancillary services and peak capacity costs.

   - Revenue neutrality adjustment – *fixed cost per hour* – The remaining, fixed components of total annual utility costs that go into retail rates (taxes, metering, billing costs, etc.) are then calculated and spread out over all hours of the year. The result, when added to the hourly marginal cost of electricity, is an annual total electricity cost valuation that corresponds to the total electricity revenue requirement of the utilities.

While the details of the Title 24 TDV methodology can be complex, at root the concept of TDV is quite simple. It holds the total cost of energy constant at forecasted retail price levels but gives more weight to on-peak hours and less weight to off-peak hours. This means that energy efficiency measures that perform better on-peak will be valued more highly than measures that do not.

1.2 Overview of Key Assumptions

The economics for the 2013 Title 24 Building Energy Efficiency Standard TDVs, like those developed for the 2005 and 2008 T24 updates, are based on long-term (15- and 30-year) forecasts that reflect existing energy trends and state policies. Note that the timeframe of the economic analysis used in the 2013 TDVs spans the years 2011 to 2040 for the 30-year analysis and 2011 to 2025 for the 15-year analysis. This choice was made prior to the decision to release the updated Title 24 standards in 2013. While it would be possible to update the analysis period to begin in 2013 the changes to the results would be relatively minor compared to the inconvenience of re-releasing the TDV factors and requiring new measure analysis. Also note that the TDV NPV costs are reported in 2011 dollars, and are formatted to the 2009 calendar year and 2009 weather year file data.

To reflect current state policy, the 2013 Title 24 TDV factors include the costs and generation impacts of the Renewable Electricity Standard (requiring 33% renewables by 2020) as well as other policies around the state law (AB 32) which requires a reduction in greenhouse gas (GHG) emissions to 1990 levels by 2020. The table below describes the key assumptions included in the 2013 TDV numbers.

Table 1. Key Assumptions in 2013 TDVs

Input	Description
Overview:	***TDVs reflect current state policy and energy trends.***
Retail rate escalation	Retail rate escalated at a rate consistent with the E3/CARB 33% RES Calculator impacts: real rate escalation of 2.1%/yr for 2013 – 2020. From 2021 – 2040, rates are escalated at real rate of 1.4%/year, the rate of the "natural gas only" build-out case from the E3/CARB 33% RES Calculator tool.
CO_2 price	Net present value of 2009 Market Price Referent CO_2 price forecast, which begins at about \$14/ton in 2013 and escalates to \$57/ton, in real \$2010 dollars, by 2040.
CO_2 price policy	Assume that a CO2 pricing policy will not further increase rates beyond the retail rate assumptions above (i.e. future CO_2 value is used to offset any impacts to residential retail rates). However, CO_2 prices do affect the electricity market price shape, increasing the value of on-peak electricity.
Renewable Electricity Standard (RES)	Assume California meets a 33% RES by 2020. The market price shape of electricity is determined by the "High Wind" 33% RES case developed as part of the CEC's "Electricity System Implications of 33 Percent Renewables" Study completed in June 29, 2009.
Other Policies (AB 32 Scoping Plan, Once-through cooling regulations)	Assume statewide energy efficiency, rooftop solar PV and combined heat and power generation by 2020 are consistent with the AB 32 Scoping Plan goals and state compliance with proposed regulations on once-through cooling of coastal thermal power plants. The impact of these policies are reflected in the market price shape from the "High Wind" 33% RES case developed as part of the CEC's "Electricity System Implications of 33 Percent Renewables" Study completed in June 29, 2009.

Input	Description
Real Discount Rate	3% real discount rate, (5% nominal).

1.3 Key Changes in the 2013 TDVs Compared to the 2008 Methodology

This section summarizes the key changes to the 2013 TDV methodology compared to the 2008 approach. Overall, the 2013 methodology represents refinements and improvements to the 2008 methodology but does not include any major departures from the prior approach.

1.3.1 CORRELATING WEATHER AND LOAD

A major improvement in the 2013 TDV methodology is that for the first time we were able to correlate the electricity market price shapes with the 2013 statewide typical weather year files. This means that the "typical weather year" hottest days of the year will also reflect the highest TDV value hours of the year. In the past, there was a fairly close link between the weather files and the TDV shapes, but due to limitations in the prior weather data files, there was no way to make that link explicit.

In the 2013 TDVs, the market price shapes are developed using a production simulation dispatch model. The dispatch model does not use temperature or weather as an input, rather, the model uses annual hourly electricity load profiles by region as inputs. Since electricity demand is highly correlated with temperature in California, we developed a new set of annual hourly load profiles for each of the 18 California regions in the simulation model. E3 used statistical analysis to capture the historical relationship between temperature and electricity demand in each region and regression techniques to forecast new load shapes that correspond to the new Title 24 weather files that were developed for the Energy Commission by Whitebox Technologies.

The regression analysis used to develop weather-correlated load shapes accounts for:

- Weather effect (dry bulb temperature, dew point temperature, cooling and heating degree hours & 3-day lagged cooling and heating degree days)
- Time-of-use effect (hour, day, month, holidays)
- Skew of load data (hourly distribution has long tail)
- Peak loads (secondary regression captures peak hours for temps above 75˚F)
- Load growth (data are normalized for peak load)

A more detailed description of the statistical approach employed to develop the weather-correlated load shapes is provided in Appendix A.

1.3.2 LONG-TERM MARKET PRICE SHAPES

Another improvement in the 2013 TDV methodology is that it includes a forecast of how the market price shape for electricity will change as the state increases the amount of energy efficiency and renewable energy on the grid through 2020 to comply with the Global Warming Solutions Act of 2006 (AB 32).

The market price shapes are developed using two runs from the Commission's production simulation dispatch model. The model is first run for a 2012 simulation year, reflecting the current generation resource mix. Next, the model is run using a 2020 simulation year, where the generation mix is assumed to be 33% renewables, in compliance with the state's 33% Renewable Electricity Standard (RES). We use the Commission's "high wind" penetration scenario for this case.

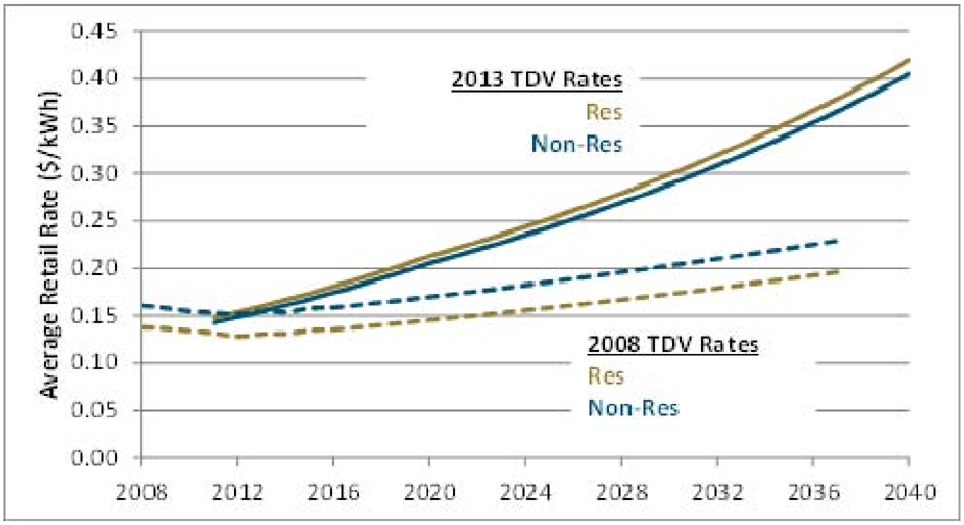
The 2013 TDVs include an annual hourly price shape forecast for the 30-year period between 2011 and 2040. For each year up to 2020, the market price shape smoothly transitions between the 2012 and the 2020 production simulation results. Beyond 2020, the market price shape is held constant.

1.3.3 RETAIL RATE FORECAST

The 2013 TDVs include a higher retail rate forecast than the 2008 TDVs. The 2008 forecast assumed a very low escalation of retail rates, consistent with the Commission's rate forecast at that time. The 2013 retail rate forecast reflects the expected rate impacts in 2020 of complying with the state's AB 32 Scoping Plan, including a 33% RES and higher energy efficiency, resulting in a 2.1% per year real rate increase through 2020, slowing to a 1.4% per year real rate increase thereafter.

Figure 1 compares the rate forecasts from the two vintages of TDVs, showing the substantially higher rate of escalation assumed in the 2013 TDVs. It is also worth noting that in the 2013 retail rates, the residential rates are slightly higher than the non-residential rates, consistent with current statewide average rates. In 2008, the opposite was true, with nonresidential rates slightly higher than residential rates. This difference means that the 2013 TDVs show a higher increase relative to 2008 for the residential TDVs than for the nonresidential TDVs.

Figure 1. Comparison of retail rate forecasts in the 2008 and 2013 TDVs.[1]



1.3.4 ELECTRICITY COSTS AND UTILITY SERVICE TERRITORIES

In the 2008 TDV methodology, many of the components of the avoided cost of electricity were designed to vary by electric utility service territory as well as by climate zone, including the average retail rate adjuster and the avoided transmission and distribution (T&D) costs. These utility-specific differences, especially the differences in T&D costs between service territories, created significant discontinuities between climate zones that were predominately served by SDG&E versus climate zones predominately served by SCE or PG&E.

[1] All annual forecasts shown in this report are expressed in nominal dollars.

When the decision was made to use the TDV factors as part of the formula for determining New Solar Homes Partnership incentives, these sharp differences between climate zones created large differences in the solar PV incentives offered across otherwise similar regions.

Since the TDV factors are now used to determine incentive levels, the 2013 TDVs now use average statewide cost forecasts for the retail rate adjustment and the avoided T&D costs. The only components of the avoided costs that vary by utility service territory are the line loss factors and the market price shape assumptions, neither of which will create significant differences for incentive setting purposes.

In addition to the changes described above, there are a number of other smaller adjustments to the 2013 TDVs. These include an updated approach to calculate capacity value using MRTU real time market data that is now available, and a calculation of marginal CO_2 emissions rates using monthly gas spot prices in the implied heat rate calculation and the line loss factors, as described in Section 3.2 of this report. Other updates to the data inputs in the 2013 TDVs compared to the 2008 TDVs are summarized in Appendix B.

2 Approach

2.1 Overview of Avoided Cost of Electricity

The TDV values reflect the hourly or monthly 'shape' of the total costs of the three fuels affected by the Title 24 standards; electricity, natural gas, and propane, including wholesale market costs, delivery, and emissions costs. In each case the underlying shape of the marginal cost is adjusted with a flat adder to the 'level' of forecasted retail rates.

For each climate zone, the avoided cost is calculated as the sum of five components, each of which is summarized in Table 2.

Table 2. Components of marginal energy cost

Component	Description
Generation Energy	Estimate of hourly wholesale value of energy measured at the point of wholesale energy transaction
System Capacity	The costs of building new generation capacity to meet system peak loads
Ancillary Services	The marginal costs of providing system operations and reserves for electricity grid reliability
T&D Capacity	The costs of expanding transmission and distribution capacity to meet peak loads

Component	Description
Greenhouse Gas Emissions	The cost of carbon dioxide emissions (CO_2) associated with the marginal electricity generation resource

In the value calculation, each of these components is estimated for each hour in a typical year and forecasted into the future for 30 years. The hourly granularity of the avoided costs is obtained from several sources. The wholesale price of electricity shape is obtained from two production simulation dispatch model runs. Other components of the value calculation are derived by shaping forecasts of the average value of each component with historical day-ahead and real-time energy prices reported by the California Independent System Operator (CAISO's MRTU system). Table 3 summarizes the methodology applied to each component to develop the hourly price shapes.

Table 3. Summary of methodology for avoided cost component forecasts

Component	Basis of Annual Forecast	Basis of Hourly Shape
Generation Energy	Combination of market forwards through 2014 and a long-run forecast of California gas prices through 2040	Energy Commission production simulation dispatch model results using 2012 and 2020 test years
System Capacity	Fixed costs of a new simple-cycle combustion turbine, less net revenue from energy and AS markets	Hourly allocation factors calculated as a proxy for rLOLP based on loads from production simulation dispatch model results
Ancillary Services	Scales with the value of energy	Directly linked with energy shape
T&D Capacity	Survey of investor owned utility transmission and distribution deferral values from recent general rate cases	Hourly allocation factors calculated using hourly temperature data

Component	Basis of Annual Forecast	Basis of Hourly Shape
Greenhouse Gas Emissions	Synapse Consulting 2008 forecast: Mid-Level CO_2 price forecast developed for use in electricity sector IRPs	Directly linked with energy shape based on implied heat rate of marginal generation, with bounds on the maximum and minimum hourly value
Retail Rates	E3/CARB 33% RES Calculator retail rate forecast through 2020	Constant allocation factor, does not vary by hour

The hourly time scale used in this approach is an important feature of the TDVs. Figure 2, below, shows a one-week snapshot of the avoided costs, broken out by component, in Climate Zone 2. As shown, the cost of providing an additional unit of electricity is significantly higher in the summer afternoons than in the very early morning hours. This chart also shows the relative magnitude of different components in this region in the summer for these days. The highest peaks of total cost shown in Figure 2 of over $1,600/MWh are driven primarily by the allocation of capacity costs and transmission and distribution (T&D) costs to the highest load hours, as well as by higher wholesale energy prices during the middle of the day.

Figure 2. One week snapshot of energy values (Climate Zone 2)

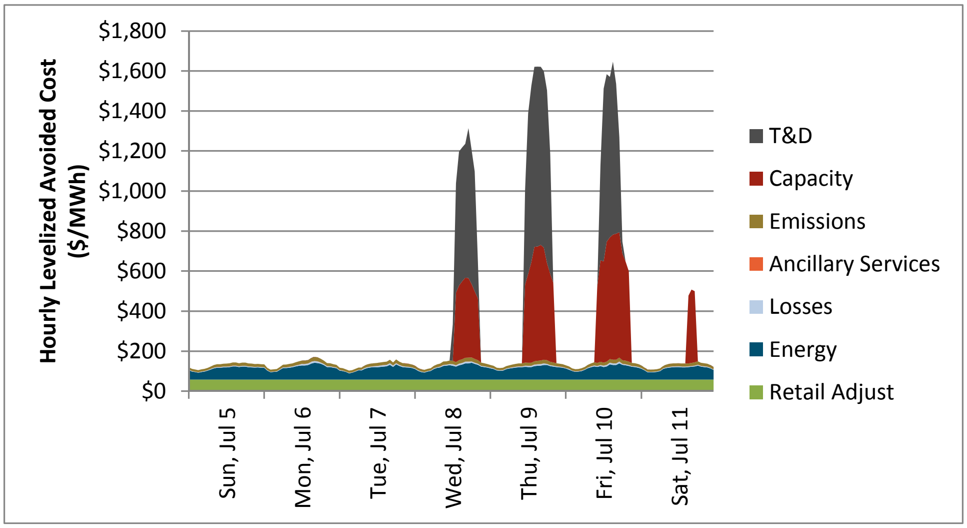
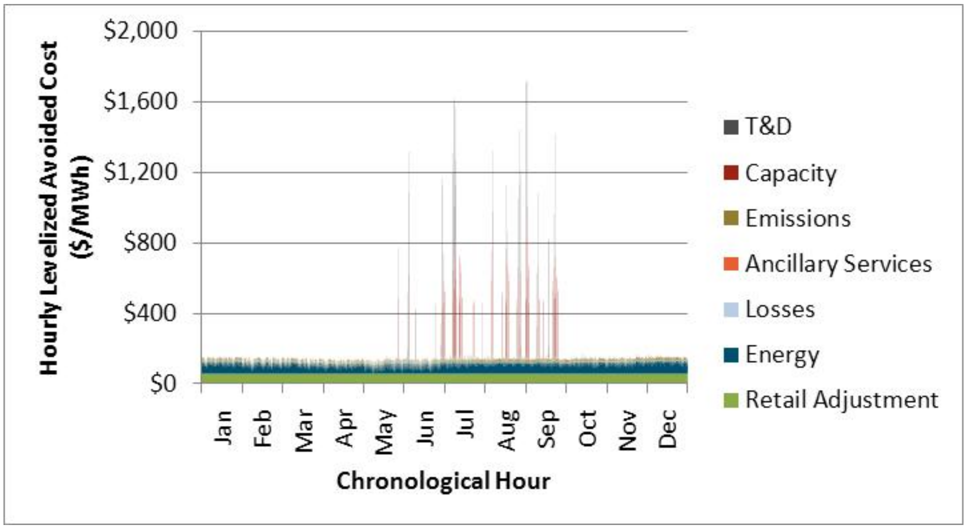


Figure 3 shows the annual chronological set of estimated values for Climate Zone 2 for an entire year. There are several hundred high hourly spikes driven by hours with the highest loads. The spikes are caused by the costs of adding capacity to deliver electricity in the few highest load hours. For the rest of the hours, the value of energy in the wholesale market is the primary component; it fluctuates by time of day and by season to reflect the trends of California's wholesale markets.

Figure 3. Annual levelized energy values (Climate Zone 2)



2.2 Calculating Net Present Value TDVs

Once the 30-year forecast of energy costs have been developed (in terms of $/kWh), the next step is to calculate the "lifecycle" value of energy savings. To do this, we calculate the net present value (NPV) of each hour's energy cost over a 15-year and 30-year nonresidential analysis period and over a 30-year residential analysis period. The NPV is calculated by applying a 3% real (inflation adjusted) discount rate, inflation is assumed to be 2% per year. Next, the NPV TDV is converted from a cost per unit energy ($/kWh) to an energy only unit (kWh/Btu). The TDV values are presented in terms of energy units for the following reasons:

+ Describing TDV in terms of energy units is consistent with past performance method compliance methods. The intent is to minimize the impact of TDV on practitioners; TDV energy units are simply substituted for source energy, which was the original unit of analysis.

+ Converting the TDV cost units to energy units makes it less likely that someone might mistakenly interpret TDV savings as an estimate of the dollar savings that an individual building owner might see by implementing the Tile 24 standard. Given that local utility rates vary over time and across regions, and given that actual building operating practices can vary significantly, it was not desirable to imply that the TDV savings are the same as the dollar savings that any single building owner might realize.

TDVs are converted to energy units using the same NPV cost in real dollars of natural gas as was applied in the 2005 and 2008 standards. By using the same conversion factor (in real dollars) in each Title 24 update, the relative stringency of the TDVs can be more easily compared across periods.

The nonresidential 15-year conversion factor (based on the 2005 forecasted NPV gas cost) is $0.089/kBtu expressed in 2011 dollars. The residential conversion factor (based on the 2005 forecasted NPV gas cost) is $0.173/kBtu in 2011 dollars.

For evaluating the cost-effectiveness of new measures, the annual TDV energy savings can be multiplied by the following standardized factors, shown in the table below in NPV $/kBtu in 2011 dollars.

Table 4. TDV Conversion Factors, NPV 2011$/kBtu

	NPV (30-year)	NPV (15-year)
Low-Rise Residential	$0.1732	n.a.
Nonresidential & High-rise Residential	$0.1540	$0.0890

This conversion step from “TDV dollars” to “TDV energy factors” is shown mathematically in the equation below:

$$\text{TDV energy factors} = \frac{\text{TDV Dollars}\left[\text{NPV\$/kWh}\right]}{\text{Forecasted Cost}\left[\text{NPV\$/TDV kBtu}\right]} = \frac{\frac{\text{NPV\$}}{\text{kWh}}}{\frac{\text{NPV\$}}{\text{TDV kBtu}}} = \frac{\text{TDV kBtu}}{\text{kWh}}$$

Just like TDV dollar values, the TDV energy factors vary for each hour of the year. To evaluate the TDV valuation of a measure, each hour's electricity savings is multiplied by that hour's TDV energy value. As shown below, this yields an annual savings figure in terms of TDV kBtu.

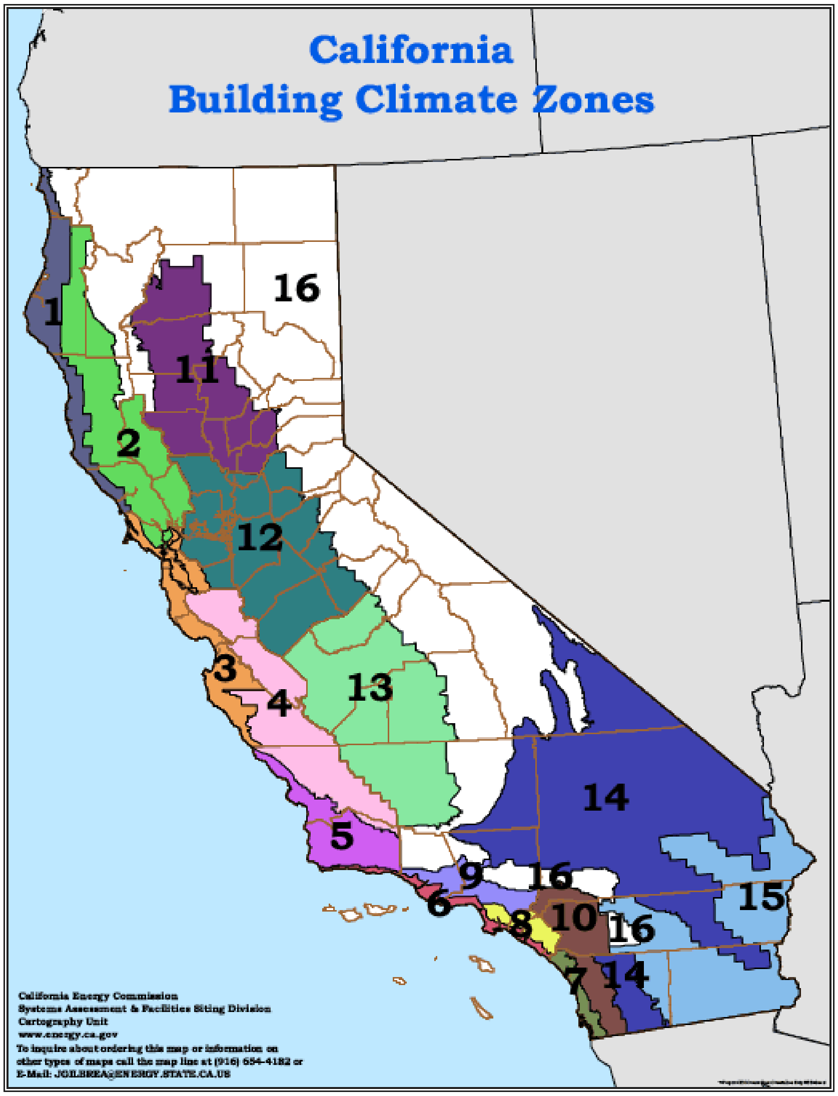
$$\text{Annual TDV Savings}\left[\text{TDV kBtu}\right] = \sum_{h=1}^{8{,}760} \text{Energy Savings}_h \left[\text{kWh}\right] \times \text{TDV Energy Factor}_h \left[\frac{\text{TDV kBtu}}{\text{kWh}}\right]$$

3 Electricity Base TDVs: Data Sources and Methodology

3.1 Climate Zone Mapping

In each hour, the value of electricity delivered to the grid depends on the point of delivery. The Title 24 Standard uses sixteen California climate zones in order to differentiate the changing value of electricity across different regions in California. These climate zones group together areas with similar climates, temperature profiles, and energy use patterns in order to differentiate regions in a manner that captures the effects of weather on energy use. Figure 4 is a map of the Title 24 climate zones in California.

Figure 4. California Climate Zones



Each climate zone has a single representative city, which is specified by the California Energy Commission. These cities are listed in Table 5, along with the IOU service territory that serves the majority of the load in each climate zone.

Table 5. Representative Cities for California Climate Zones

Climate Zone	Representative City	Majority IOU Territory
CEC Zone 1	Arcata	PG&E
CEC Zone 2	Santa Rosa	PG&E
CEC Zone 3	Oakland	PG&E
CEC Zone 4	Sunnyvale	PG&E
CEC Zone 5	Santa Maria	SCE
CEC Zone 6	Los Angeles	SCE
CEC Zone 7	San Diego	SDG&E*
CEC Zone 8	El Toro	SCE
CEC Zone 9	Pasadena	SCE
CEC Zone 10	Riverside	SCE
CEC Zone 11	Red Bluff	PG&E
CEC Zone 12	Sacramento	PG&E
CEC Zone 13	Fresno	PG&E
CEC Zone 14	China Lake	SCE
CEC Zone 15	El Centro	SCE
CEC Zone 16	Mount Shasta	PG&E

* Climate zone 7 uses SCE market price shape data.

Most of the components of avoided costs in the 2013 TDVs vary by climate zone but do not vary by IOU service territory. The two exceptions are for avoided line losses and the market price shapes developed in the CEC's production simulation dispatch model, which vary based on the IOU service providers specified in Table 6 (note that Climate Zone 7, though served by SDG&E, uses the SCE market price shape for consistency with the other Southern regions). All other components of the avoided cost of electricity are calculated using statewide average utility costs, including residential and nonresidential retail rates and avoided transmission and distribution costs. This represents a slight departure from the 2008 methodology, where IOU-specific utility costs were applied to most components of the avoided costs.

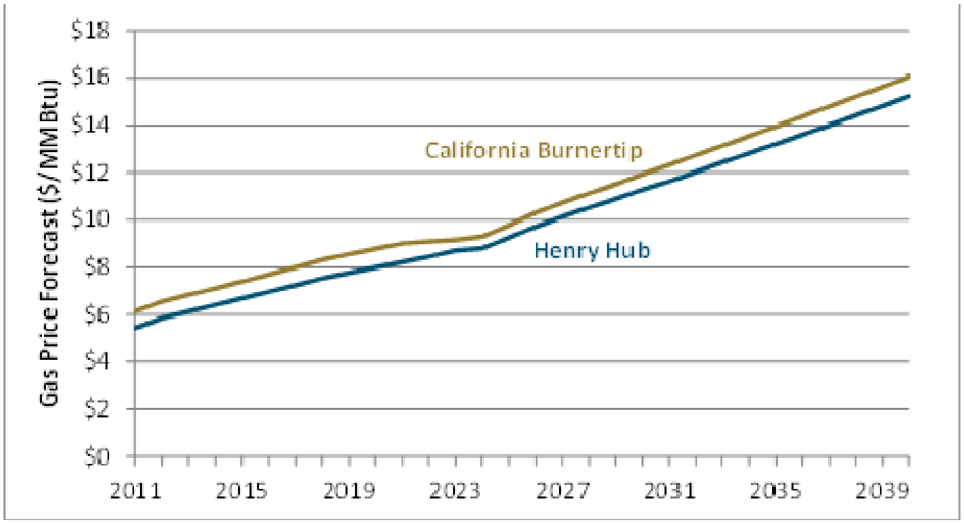
The reason that E3 has moved to a more unified statewide average costing approach is two-fold. First, over a 15 or 30-year analysis period, current differences between IOU costs may change. Second, the TDVs are used by the Commission in the New Solar Homes Partnership (NSHP) program, which bases solar PV incentive levels in part on TDV factors. From a policy perspective, it was not desirable to have significantly different incentives being offered in neighboring climate zones due to differences in IOU utility costs, as was the case using the 2008 TDVs. By using statewide average costs in the 2013 TDVs, the large differences between the climate zones seen in 2008 have been reduced.

3.2 Avoided Cost of Electricity Inputs

3.2.1 NATURAL GAS PRICE FORECAST

The natural gas price forecast, which is the basis for the calculation of the electricity market prices, is taken from the CPUC MPR 2009 Update. This forecast is based upon NYMEX Henry Hub futures through 2020, and an average of proprietary forecasts beyond 2020, average basis differentials, and delivery charges to utilities. The forecast is shown in Figure 5.

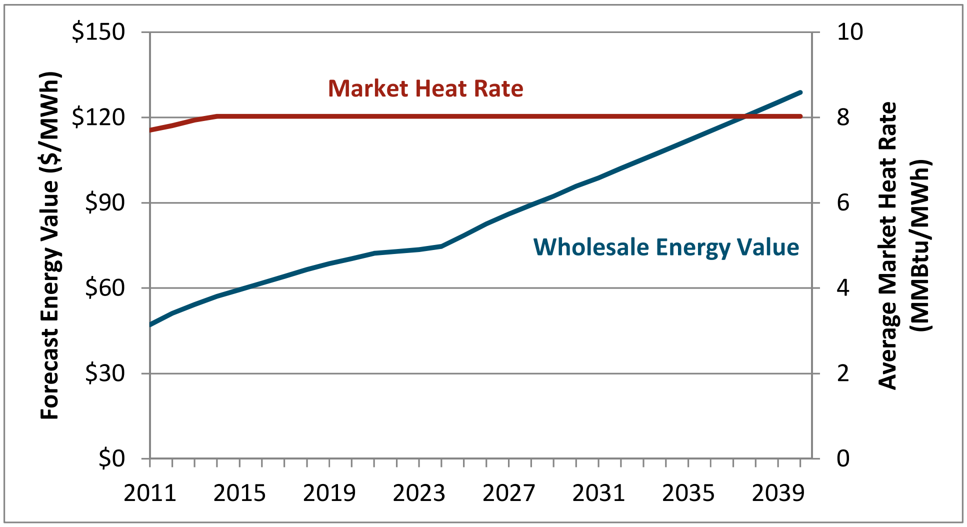
Figure 5. Natural gas price forecast



3.2.2 ENERGY GENERATION

The avoided cost of energy reflects the marginal cost of generation needed to meet load in each hour. The forecast values of energy include short and long-run components. The wholesale value of energy through 2014 is based on market forwards for Northern and Southern California (NP15 and SP15). The long-run value of energy is calculated based on the assumption that the average market heat rate will remain stable; the implied market heat rate based on 2014 forwards is extended through 2040. The long-run value of energy is calculated by multiplying the gas price forecast by this market heat rate. This forecast is shown in Figure 6.

Figure 6. Forecast of wholesale energy value derived from gas price forecast and market heat rates



The hourly shape for wholesale energy prices is developed using the California Energy Commission production simulation dispatch model runs. The hourly load shapes used in the model are designed to be correlated with the Title 24 revised statewide weather data.

The hourly values of energy are adjusted by loss factors to account for losses between the points of wholesale transaction and retail delivery. The loss factors used in the avoided cost calculation vary by utility, season, and TOU period; and are summarized in

Table 6.

Table 6. Marginal energy loss factors by utility and time period

Time Period	PG&E	SCE	SDG&E
Summer Peak	1.109	1.084	1.081
Summer Shoulder	1.073	1.080	1.077
Summer Off-Peak	1.057	1.073	1.068
Winter Peak	-	-	1.083
Winter Shoulder	1.090	1.077	1.076
Winter Off-Peak	1.061	1.070	1.068

3.2.3 RESOURCE BALANCE YEAR

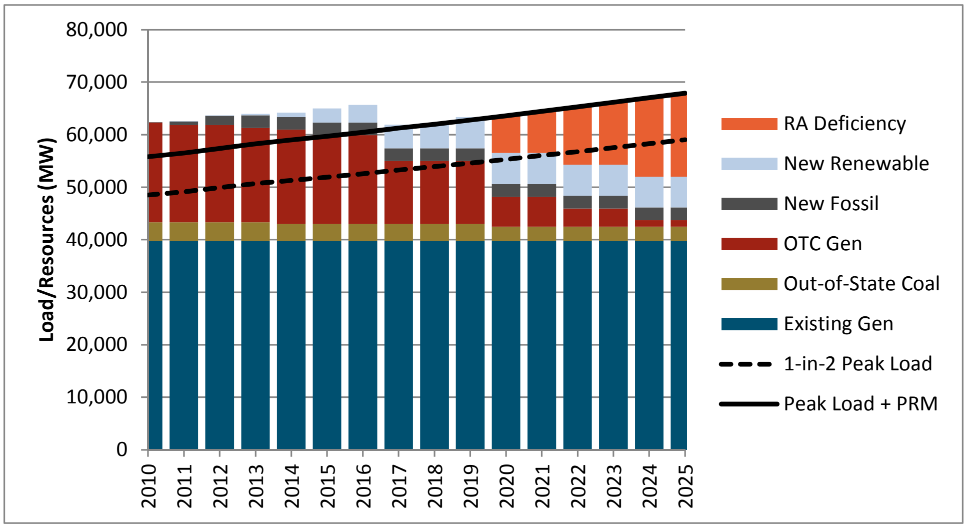
The resource balance year represents the first year in which system capacity would be insufficient to meet peak period demand plus the reserve margin. In the evaluation of the avoided cost of electricity, the determination of the resource balance year represents the point at which the forecasts for energy and capacity value transition from short-run to long-run time scales; after this point, the energy and capacity values should capture the all-in costs of the new plants whose construction would be required to maintain resource adequacy. The avoided cost after the resource balance year is therefore based on the long run marginal avoided cost of new electricity generation.

The resource balance year is evaluated by comparing the CEC's forecast of peak loads in California with California's expected committed capacity resources. The forecast for expected capacity includes several components: 1) existing system capacity as of 2008, net of expected plant retirements; 2) fossil plants included in the CEC's list of planned projects with statuses of "Operational," "Partially Operational," or " Under Construction"; and 3) a forecast of renewable capacity additions to the system that would be necessary to achieve California's 33%

Renewable Electricity Standard by 2020 based on E3's 33% RES Calculator developed for the California Air Resources Board proceeding.[2]

The load-resource balance is shown in Figure 7 below; based on this analysis, 2020 has been selected as the resource balance year for California and is driven primarily by the retirement of once-through cooling generators. This represents the first year in which committed capacity resources would be insufficient to meet the expected peak system demand and required reserve margin.

Figure 7. Evaluation of the resource balance year in California



3.2.4 SYSTEM CAPACITY AND CAPACITY COST ALLOCATION

The generation capacity value captures the reliability-related cost of maintaining a generator fleet with enough capacity to meet each year's peak

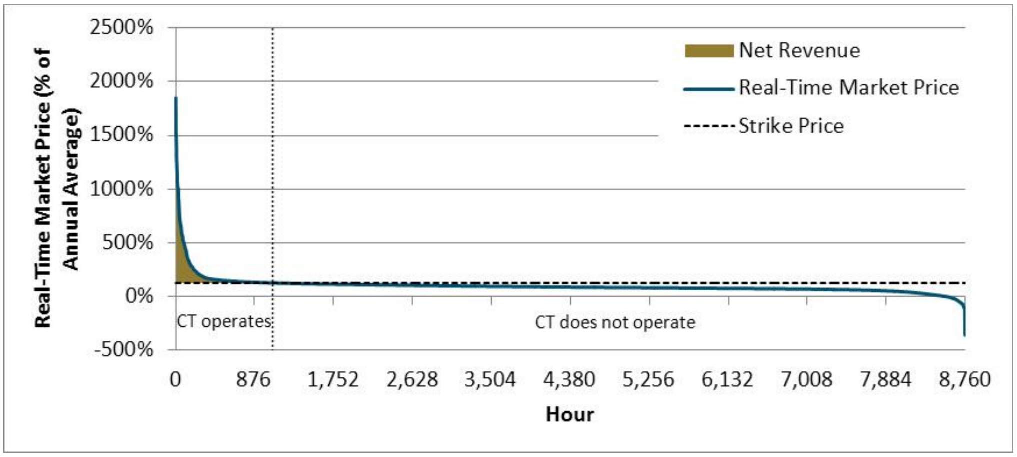
[2] See California Air Resources Board Economic Modeling Tools, "E3 RES Calculator": http://www.arb.ca.gov/research/econprog/econmodels/econmodels.htm

loads. Capacity value is calculated as the difference between the cost of a combustion turbine (CT) and the margins that the CT could earn from the energy markets.

The forecast of value includes both a short-run and a long-run component; the transition point between the two occurs in the resource balance year. The short-run value of capacity is based on the 2008 resource adequacy value of \$28/kW-yr—the relatively low value reflects the large surplus of capacity currently available on the CAISO system. Capacity value in the years between 2011 and the resource balance year 2020 is calculated by linear interpolation.

Starting in 2020, the resource balance year, the value of capacity is calculated based on the cost of a simple-cycle combustion turbine (CT), as that is the first year in which new capacity resources may be needed to meet the growth of peak loads and reliability requirements. The long-run capacity value is equal to the CT's annualized fixed cost less the net revenues it would earn through participation in the real-time energy and ancillary services markets—this figure is the "capacity residual." The TDV methodology calculates the capacity residual of the CT for each year of the avoided cost series by dispatching a representative unit against an hourly real-time market price curve and subtracting the net revenues earned from the unit's fixed costs. The hourly shape of the real-time market is based on historical real-time data gathered from CAISO's MRTU system; in each year, the level of the curve is adjusted by the average wholesale market price for that year. The CT's net revenues are calculated assuming that the unit dispatches at full capacity in each hour that the real-time price exceeds its operating cost (the sum of fuel costs and variable O&M) plus a 10% bid adder, earning the difference between its operating cost and the market price. In each hour where the market prices are below the operating cost, the unit is assumed to shut down, illustrated in Figure 8 below.

Figure 8. Calculation of Capacity Cost using Net Revenue of a Combustion Turbine (CT)



The net revenues earned through this economic dispatch are grossed up by 11% to account for profits earned through participation in CAISO's ancillary services markets. The final figure is subtracted from the CT's annualized fixed cost—calculated using a pro-forma tool to amortize capital and fixed operations and maintenance costs—to determine the CT residual in that year.

The CT's rated heat rate and nameplate capacity characterize the unit's performance at ISO conditions,[3] but the unit's actual performance deviates substantially from these ratings throughout the year. In California, deviations

[3] ISO conditions assume 59ºF, 60% relative humidity, and elevation at sea level.

from rated performance are due primarily to hourly variations in temperature. Based on the performance characteristics of the GE LM6000 "Sprint" technology, E3 has made the following temperature-based adjustments to the calculation of the capacity value

+ In the calculation of the CT's dispatch, the heat rate is assumed to vary on a monthly basis. In each month, E3 calculates an average day-time temperature based on hourly temperature data throughout the state and uses this value to adjust the heat rate—and thereby the operating cost—within that month.
+ Plant output is also assumed to vary on a monthly basis; the same average day-time temperature is used to determine the correct adjustment. This adjustment affects the revenue collected by the plant in the real-time market. For instance, if the plant's output is 90% of nameplate capacity in a given month, its net revenues will equal 90% of what it would have received had it been able to operate at nameplate capacity.

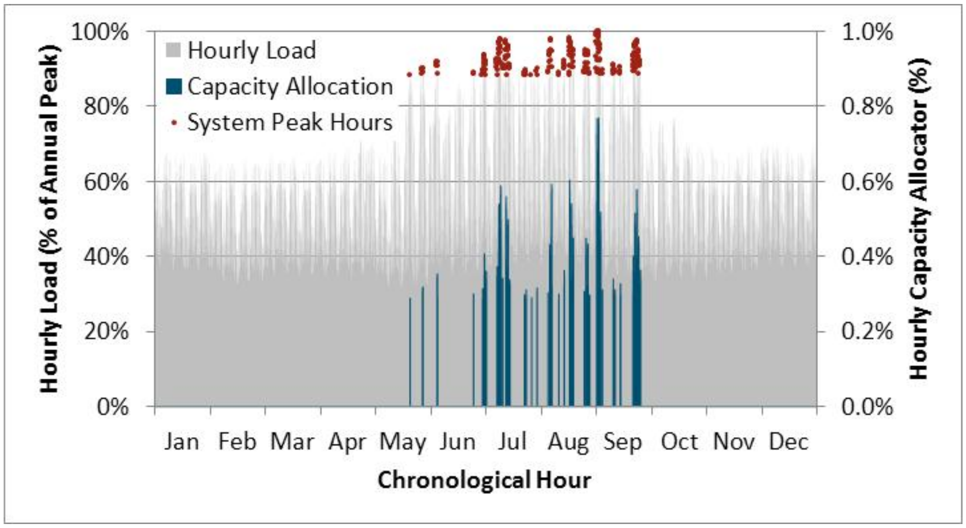
The resulting capacity residual is originally calculated as the value per nameplate kilowatt—however, during the peak periods during which a CT is necessary for resource adequacy, high temperatures will result in a significant capacity de-rate (by approximately 1% per 2.5 degrees above 60 degrees Fahrenheit). Consequently, the value of capacity is increased by approximately 9% to reflect the plant's reduced output during the top 250 load hours of the year.

The valuation of capacity includes an adjustment for losses between point of generation and delivery. In order to account for losses, the annual capacity value is multiplied by the utility-specific loss factor applicable to the summer peak period, as this is the period during which system capacity is likely to be constrained.

The loss-adjusted forecast of capacity value is further grossed up by 115% to reflect savings in the planning reserve margin (PRM). The California Public Utilities Commission requires each load-serving entity to maintain enough capacity to meet its peak demand plus a planning reserve margin of 15%. Based on the PRM requirement a peak load reduction of a single kilowatt would reduce the amount of capacity needed by 1.15kW.

The adjusted capacity value is allocated across the 250 hours of the year in which system loads are the highest; these are the hours in which marginal changes in consumption could result in avoided capacity costs. The capacity allocation factors used are a simplified proxy for relative loss of load probabilities (rLOLP) sometimes used to allocate generation capacity costs. These hourly allocation factors spread generation capacity value across the top 250 hours of each year based on system load. Figure 9 below, shows the generation capacity cost allocation factors compared to hourly loads.

Figure 9. Allocation of generation capacity costs (Climate Zone 2)



The following calculation sequence is used to compute a capacity cost allocation factor in each of the top 250 system load hours. This methodology is applied in the calculation of the hourly avoided cost of electricity:

1. Compute the system capacity that provides 7% operating reserves = peak load * 1.07
2. Compute a relative weight in each hour as the reciprocal of the difference between the load in each of the top 250 hours and the planned system capacity
3. Normalize the weights in each hour to sum to 100%

Cost and performance assumptions for a new simple cycle gas turbine, used in the capacity cost calculation, are based on the California Energy Commission's Cost of Generation report, as shown in Table 7 below.

Table 7. Natural Gas Combustion Turbine Cost and Performance Assumptions (2009 $)

	Combustion Turbine Assumptions
Heat Rate (Btu/kWh)	9,300
Plant Lifetime (yrs)	20
In-Service Cost ($/kW)	$1,365
Fixed O&M ($/kW-yr)	$17.40
Variable O&M ($/kW-yr)	$4.17
Debt-Equity Ratio	60%
Debt Cost	7.70%
Equity Cost	12.0%

3.2.5 ANCILLARY SERVICES (A/S)

The value of avoided ancillary services procurement is treated as a flat percentage multiplier on top of the energy value. This approach reflects the fact that the value of ancillary services is mildly correlated with the value of energy in any given hour, but other factors also affect the value of A/S. Since the overall value of A/S remain relatively small in the market, it is appropriate to use an approximation, based on a multiplier of 1% of the energy value in each year. This multiplier is based on California Independent System Operator (CAISO MRTU) market prices for energy and reserves from 2009-2010. The new CAISO market design has substantially reduced ancillary service costs. Load reduction (e.g. efficiency) is only credited with the value of avoided procurement of spinning and non-spinning reserves.

3.2.6 TRANSMISSION AND DISTRIBUTION CAPACITY & COST ALLOCATION

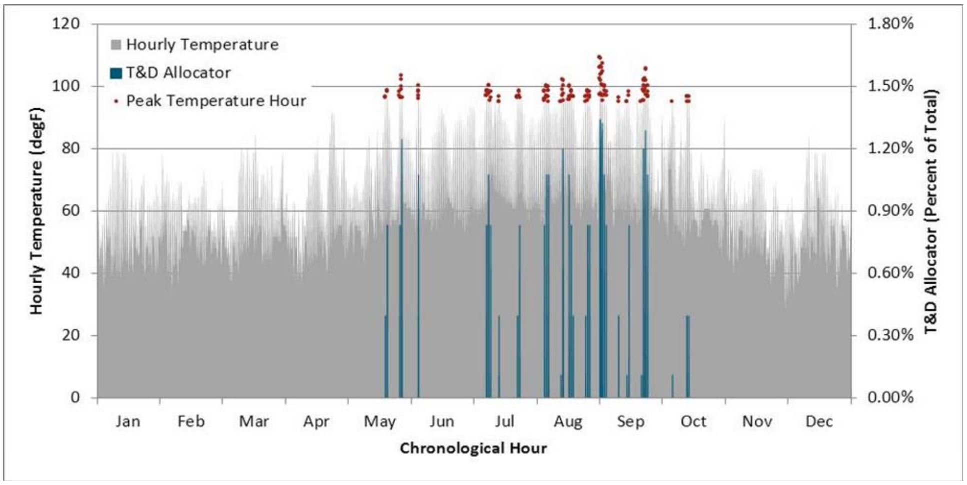
The avoided costs include the value of the potential deferral of transmission and distribution (T&D) network upgrades that could result from reductions in local peak loads. The marginal value of T&D deferral is highly location-specific; E3 has gathered utility general rate case filing data from the three largest IOU T&D investment plans and computed the cost of planned T&D investments on a $/kW-Yr. basis. Using these data, E3 calculated load-weighted statewide average deferral values for both transmission and distribution infrastructure. As with generation energy and capacity, the value of deferring transmission and distribution investments is adjusted for losses during the peak period using the factors shown in the table below. These factors are lower than the energy and capacity adjustments because they represent losses from transmission and distribution voltage levels to the retail delivery point, rather than from the generator to the load.

Table 8. Losses during peak period for capacity costs

	PG&E	SCE	SDG&E
Distribution	1.048	1.022	1.043
Transmission	1.083	1.054	1.071

Since the network constraints of a distribution system must be satisfactory to accommodate each area's local peaks, the TDV methodology allocates the deferral value of T&D in each zone to the hours of the year during which the system is most likely to be constrained and require upgrades—the hours of highest local load. Because local loads are correlated with hourly temperatures in our analysis, we use hourly temperatures as a proxy to develop allocation factors for T&D value. This methodology was benchmarked against actual local load data in the 2005 Title 24 update, and remains unchanged in the 2008 and 2013 updates. This approach results in an allocation of T&D value to several hundred of the hottest and highest local load hours of the year. For example, the T&D allocators for Climate Zone 2 are shown in the figure below.

Figure 10. Allocation of T&D Costs (Climate Zone 2)



The following is a brief description of the algorithm used to allocated T&D capacity value. T&D capacity value is allocated to all hours with temperatures within 15ºF of the peak annual temperature.

1. Select all hours with temperatures within 15ºF of the peak annual temperature (excluding hours on Sundays and holidays) and order them in descending order.
2. Assign each hour an initial weight using a triangular algorithm, such that the first hour (with the highest temperature) has a weight of 2/(n+1) and the weight assigned to each subsequent hour decreases by

2/[n*(n+1)], where n is the number of hours that have a temperature above the threshold established in the first step.

3. Average the initial weights among all hours with identical temperatures so that hours with the same temperature receive the same weight.

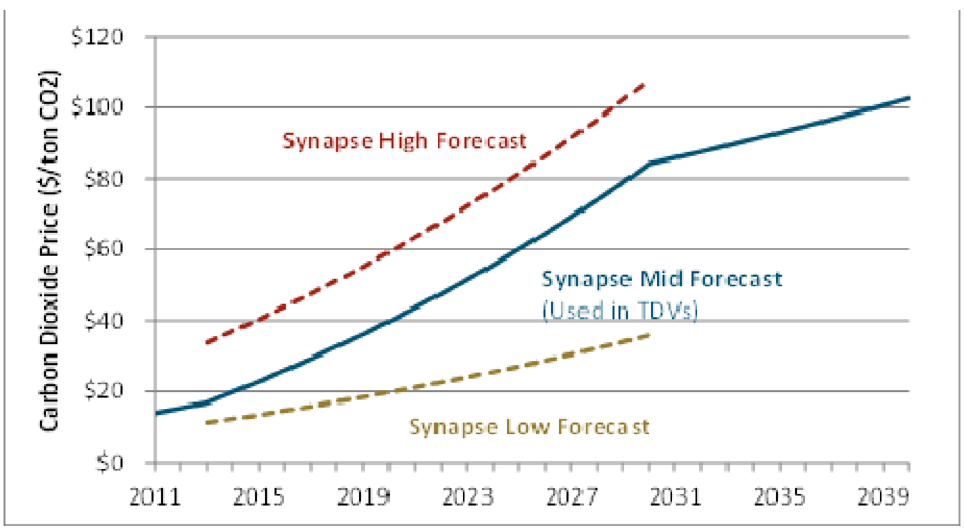
We make one further adjustment to this methodology for Climate Zone 1 (Arcata). In this Northern region, there are relatively few high temperature days, and also relatively low penetrations of air conditioners in homes and businesses. As a result, in Climate Zone 1, high temperature days are unlikely to result in the spikes in electricity demand that we see in other regions of California that have air conditioning loads which increase with higher temperatures. Unless we adjust the T&D cost allocation methodology for this region, Climate Zone 1 would show a high allocation of T&D costs to relatively few hours, resulting in high price spikes in those few hours. To spread the allocation of T&D deferral value over more hours in this climate zone, allocators are calculated for each hour within 19ºF of the peak temperature. Hours within 4ºF of the peak annual temperature are assigned the same allocator. This adjustment spreads the T&D capacity value over a larger number of hours and is justified because of the weaker correlation between temperature and peak load in this climate zone.

3.2.7 GREENHOUSE GAS EMISSIONS

The reduction of greenhouse gas emissions is a major policy priority in California, as required under the Global Warming Solutions Act of 2006 (AB 32). While there is not yet a carbon dioxide (CO_2) market established in California, the California Air Resources Board is developing a CO_2 cap and trade market, which is likely to go into effect starting in 2012. As a result, we include a market price forecast for CO_2 in the forecast of the market price shape for fuels.

While it is difficult to predict the future price of CO_2 emissions, there is precedent in California regulatory agencies for using a CO_2 price forecast. In a variety of proceedings, including the Market Price Referent (MPR) proceeding, the California Public Utility Commission uses a forecast developed by Synapse Energy Economics, a consulting firm. Synapse Energy employs a meta-analysis of various studies of proposed climate legislation to develop their CO_2 market price forecast. The Synapse "mid-level" CO_2 price forecast is used in the 2013 TDVs, as it was developed explicitly for use in electricity sector integrated resource planning and so serves as an appropriate applied value for the cost of carbon dioxide emissions in the future. Figure 11 summarizes the Synapse price forecasts; the mid-level forecast is used in the calculation of TDV avoided costs.

Figure 11. CO_2 price forecast



The CO_2 price forecast affects the cost of generation differently in different hours of the year, depending on what type of generator is operating on the margin. In California, it is generally safe to assume that natural gas is the marginal fuel in all hours. Thus, the hourly emissions rate of the marginal generator is calculated based on the same production simulation model results of the marginal generation price curve used elsewhere in the analysis. This hourly emissions curve is adjusted using the same loss factors as the hourly energy value to reflect the emissions reduction consistent with a reduction in retail load.

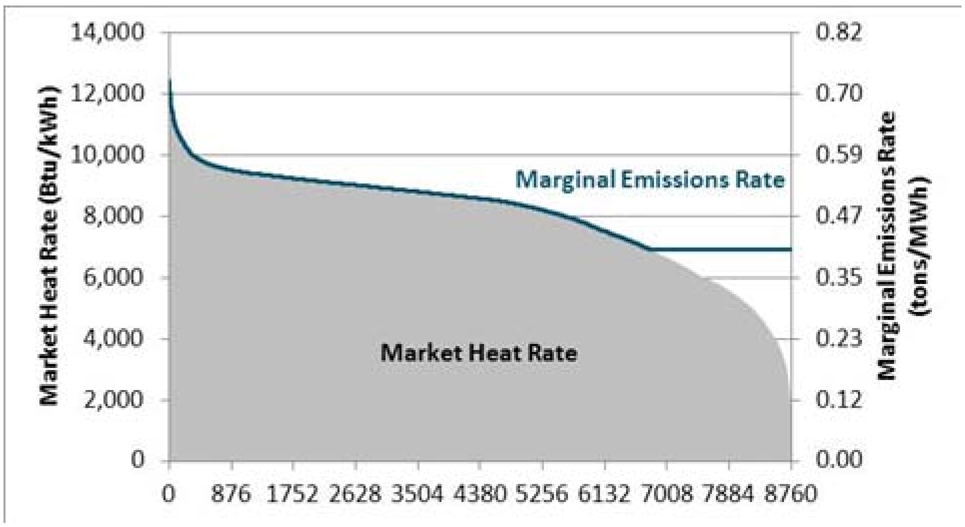
There is a direct link between higher market prices and higher emissions rates since higher market prices enable lower-efficiency generators to operate, resulting in increased rates of emissions at the margin. Of course, this relationship holds for a reasonable range of prices but breaks down when prices are extremely high or low. For this reason, the avoided cost methodology bounds the maximum and minimum emissions rates based on the range of heat rates of gas turbine technologies. The maximum and minimum emissions rates are bounded by reasonable ranges of heat rates for the “best” and “worst” performing natural gas plants shown in Table 9.

Table 9. Bounds on electric sector carbon emissions

	Proxy Low Efficiency Plant	Proxy High Efficiency Plant
Heat Rate (Btu/kWh)	12,500	6,900
Emissions Rate (tons/MWh)	0.731	0.404

Figure 12, below, shows the hourly market heat rates in California sorted from highest to lowest, as well as the implied marginal emissions rate of generation based on this heat rate.

Figure 12. Estimated Marginal Emissions Rate of Generation Based on Hourly Market Heat Rates



3.2.8 RETAIL RATE ADJUSTER

The final step in the process of developing TDV cost values is to adjust the hourly wholesale cost of energy up to the equivalent of the retail cost of energy. This step is done to ensure that the energy efficiency measures considered in the Title 24 standards process are roughly cost effective to the building owner. In other words, the TDVs reflect a modified (time-dependent) participant cost test approach to avoided costs.

A statewide retail rate forecast for residential and nonresidential customers is developed for the electricity TDVs. The electricity rate forecast is based on the

E3 "33% RES Calculator" rate forecast developed for the California Air Resources Board.[4] The statewide rate forecast, through 2020, includes the expected impacts on retail rates of meeting the state's 33% RES standard, as well as the other electricity sector goals noted in the CARB AB 32 Scoping Plan. This translates into a real rate increase of 2.1% per year for 2013 through 2020 (4.1% per year nominal increase). From 2021 to 2040, rates are escalated at real rate of 1.4% per year (3.4% nominal increase), which is equal to the escalation rate in the "natural gas only" build-out case from the E3/CARB 33% RES Calculator tool. The differential between the residential and nonresidential retail rates is based on the current statewide differential, and is assumed to remain unchanged over time. Figure 13 shows the retail rate forecast.

Figure 13. Forecast of Retail Rates Used in Calculation of Hourly TDVs

[4] See California Air Resources Board Economic Modeling Tools, "E3 RES Calculator": http://www.arb.ca.gov/research/econprog/econmodels/econmodels.htm

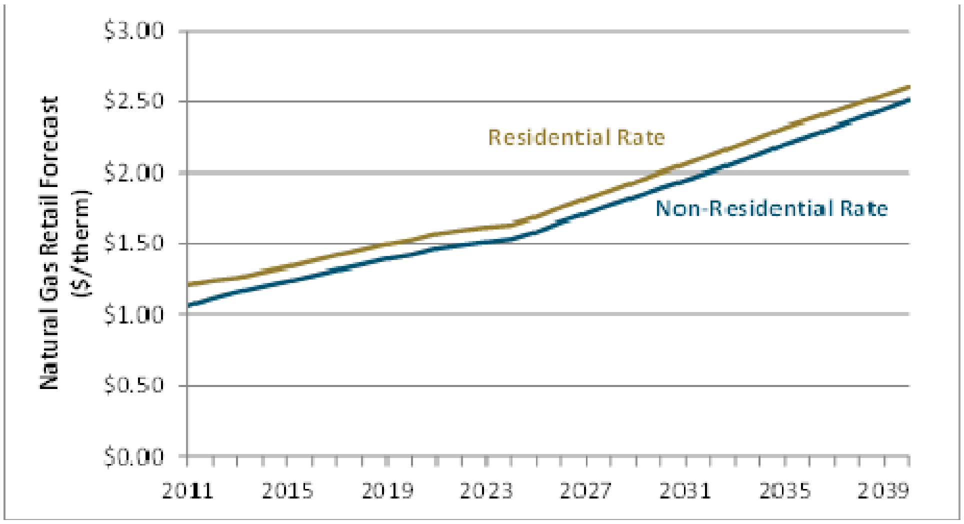
4 Natural Gas TDVs: Data Sources and Methodology

4.1 Components of TDV for Natural Gas

The natural gas TDV is based on a long-run forecast of retail natural gas prices and the value of reduced emissions of CO_2 and NO_x. The components are:

+ Retail price forecast - The natural gas retail price forecast is built up starting from the CPUC's 2009 MPR forecast of California utility gas prices, (see Section 3.2.1). The California utility gas price forecast is adjusted upwards to reflect a retail price forecast using the difference between the EIA's 2010 Annual Energy Outlook (AEO) residential retail price forecast and the electric generation gas price forecast for the Pacific region. This forecast is shaped to a monthly variation in natural gas retail prices, based on an average of historical NYMEX monthly natural gas price shapes at Henry Hub. The natural gas retail price levels used in the natural gas TDVs are shown in Figure 14, below.

Figure 14. Natural Gas Retail Rate Forecast.



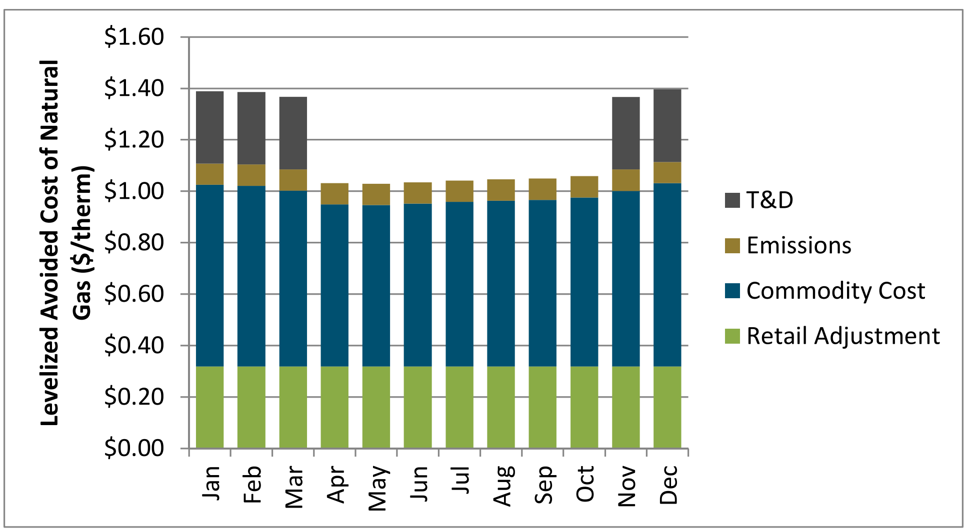
+ Emissions Costs – Emission values are calculated based on the emissions rates of combusting natural gas in typical appliances. The NO_x and CO_2 emissions rates for natural gas combustion are derived from the CPUC's energy efficiency avoided cost proceeding (R.04-04-025).
+ Distribution costs – Natural gas distribution costs include the cost of building and maintaining a natural gas pipeline distribution network. These costs are allocated to winter months, because demand for gas is highest in the winter.

In general, we seek to apply the same methodology to the development of the natural gas TDVs as to the electricity TDVs, in order to maintain as much parity between the fuel types as possible. In the case of greenhouse gas emissions and NOx emissions, this principle of parity requires a few adjustments to the natural gas TDVs. Since there is a market for NOx emissions in electricity generation, the cost of obtaining NOx permits is assumed to be included in the cost of electricity generation. However, there is no NOx emissions price for end-use natural gas combustion so we must adjust the natural gas TDV for the cost of NOx in order to treat this fuel equally with electricity.

The CO_2 price forecast impacts are kept consistent between the electricity TDVs and the natural gas TDVs. In the Base electricity TDVs, the CO_2 price affects the shape of the TDVs, but does not affect the overall level of the TDVs. This is because the market cost of CO_2 emissions is assumed to be refunded to ratepayers. The same logic is applied to the natural gas TDVs. Since CO_2 emissions do not vary by time period for natural gas combustion, the CO_2 adjustment does not affect the overall TDV shape or level for the natural gas TDVs.

Figure 15 illustrates the components of the natural gas avoided costs and the monthly variation in prices over the course of a year.

Figure 15. Monthly Variation in Natural Gas Avoided Costs



5 Propane TDVs: Data Sources and Methodology

5.1 Components of TDV for Propane Costs

The components of propane vary by month like natural gas. The components are:

+ Retail Cost - The propane forecast is based on the long-run U.S. Department of Energy (DOE) EIA 2010 Annual Energy Outlook Pacific region propane price forecast. There is a monthly variation in propane commodity costs, but not an hourly variation.
+ Emissions Costs - The emissions costs are based on the same emissions prices used in the natural gas analysis.

Figure 16 shows the Propane cost price forecast used in the analysis.

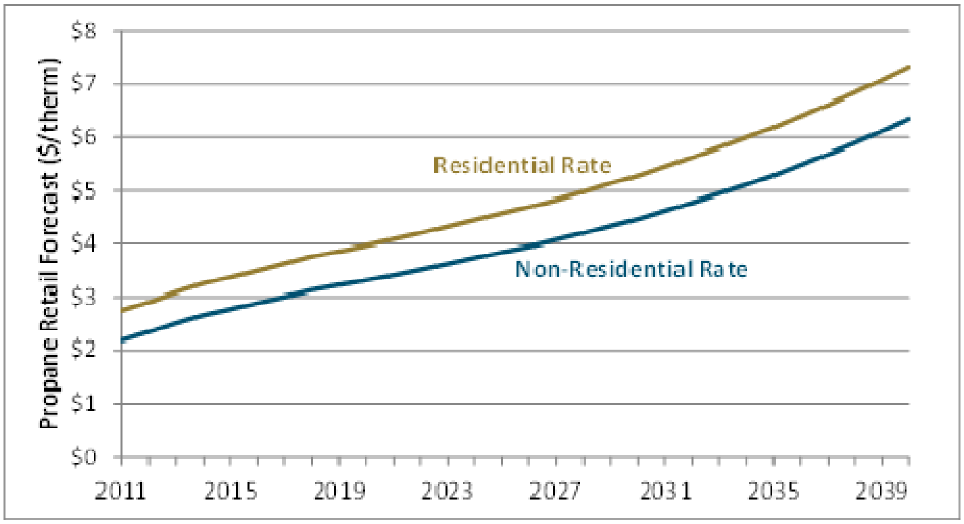


Figure 17 shows the monthly variation of the propane costs.

Figure 16. Propane Retail Rate Forecast

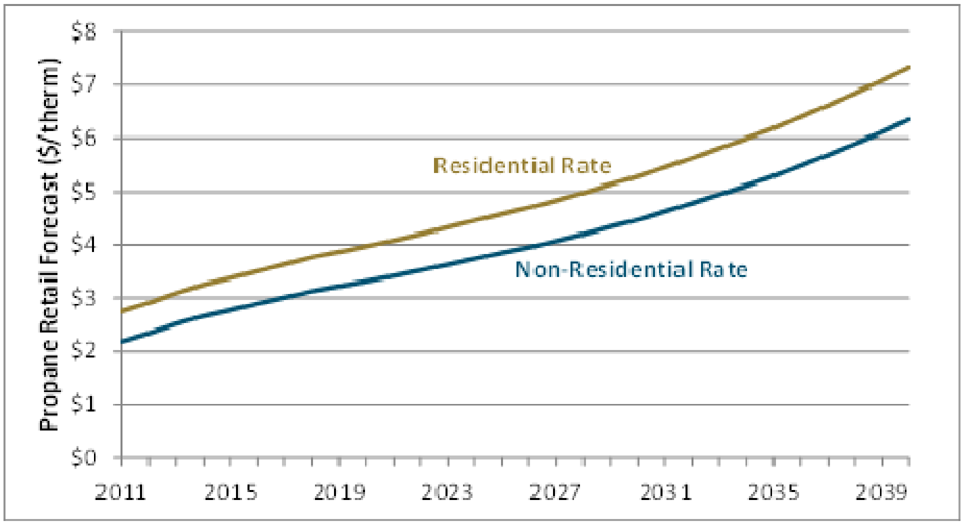
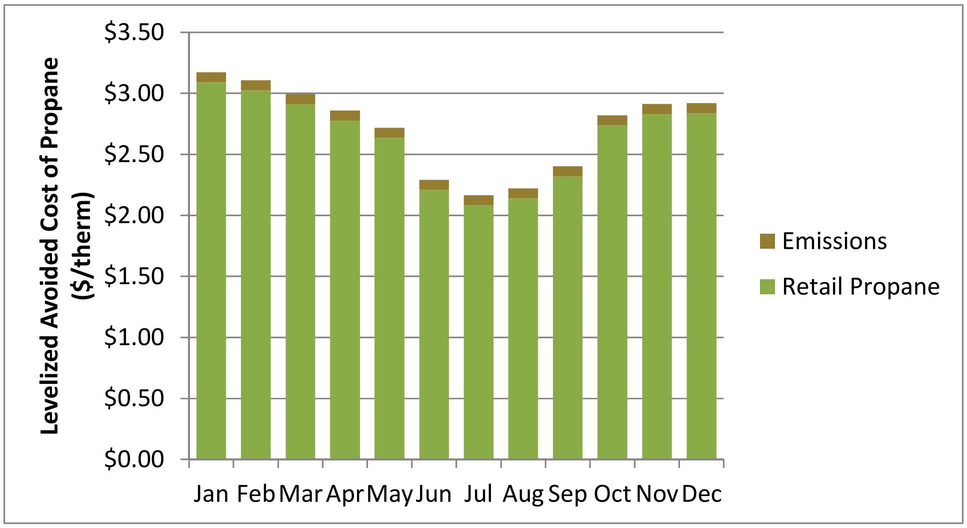


Figure 17. Monthly Variation in Propane Avoided Cost



6 Reach TDV Multipliers

6.1 Summary of Reach TDV Multipliers

The Reach TDV multipliers are developed using a similar methodology to the Base TDVs, but reflect a set of input assumptions consistent with a long-run view of carbon emission reductions. Conceptually, the Reach TDVs have been established at a level such that people today share the burden of meeting a globally sustainable CO_2 emissions level equally with our children and future generations. The Reach TDV values are consistent with a more aggressive path towards greenhouse gas reduction goals, at a level that is estimated to be consistent with a reduction in greenhouse gas emissions of 80% below 1990 levels by 2050.[5] This level of GHG reductions is consistent with California Governor's Executive Order S-3-05, and with the Intergovernmental Panel on Climate Change's (IPCC's) assessment of the global emissions reductions needed to prevent catastrophic global climate change.

To develop the Reach TDVs that share costs with future generations, a long-run estimate of CO_2 mitigation costs is used, rather than a short-run CO_2 market price forecast. In addition, the Reach TDVs include a higher retail rate forecast

[5] For a description of scenarios in which California achieves and 80% reduction in greenhouse gas emissions below 1990 levels by 2050, see: Energy and Environmental Economics, Inc. "Meeting California's Long-term Greenhouse Gas Reduction Goals," (November 2009), available at: http://www.ethree.com/public_projects/greenhouse_gas_reduction.html

in the outer years of the Reach TDVs, as compared to the Base TDVs, reflecting the higher costs of reducing GHG emissions from the electric sector on the path to the 2050 goal.

The Reach TDVs are implemented using a set of multipliers to the 2013 Base TDVs, and result in approximately 25% higher TDV values for electricity. A similar set of multipliers has been calculated for natural gas and propane. The Reach multipliers for electricity, natural gas and propane are shown in Table 10. A summary of how these multipliers are calculated is provided below.

Table 10. Reach TDV Multipliers

Sector/Measure Life	Electricity	Gas	Propane
Res 30yr	1.259	1.331	1.152
Non-Res 15yr	1.253	1.375	1.197
Non-Res 30yr	1.270	1.354	1.182

6.2 Reach TDVs: A Carbon Constrained World

For those municipalities and regions that want to voluntarily adopt a building energy efficiency standard that is more consistent with a long-run value of CO_2 reductions, we have developed an alternative long-term forecast of the avoided cost of energy, called the Reach TDVs. The Reach TDV framework is similar to the Base TDVs, with a few key changes. The same components of the underlying TDV values are used, the same climate zones are used, the same set of building energy sources is considered (electricity, natural gas, propane) and the same calculation tools and value dimensions are evaluated.

The key assumptions used to develop the Reach TDVs are described in the table below.

Table 11. Key Policy Assumptions in Reach TDVs

Input	Description
Overview of Scenario:	***Reach TDVs are reflective of a greater societal emphasis on achieving greenhouse gas reductions, and are consistent with a goal of reducing GHG emissions 80% below 1990 levels by 2050.***
Retail rate escalation	Retail rates escalated the same as Base TDVs through 2020. Escalation is assumed to be sustained through 2040 to reflect costs of achieving an 80% reduction in GHG emissions by 2050: real rate of 2.1%/yr for 2011 – 2040.
CO_2 price	Net present value of a constant CO_2 price based on the 2030 value in the "high" CO_2 price forecast from the "Synapse 2008 CO_2 Price Forecasts." Reflects a long-term GHG mitigation cost, at $73/ton every year, in real 2010 dollars.
CO_2 price policy	Assumes that the full cost and value of CO_2 reductions are seen directly by the customer, and are additional to the rate impacts discussed above. The CO_2 price thus affects both the shape of the electricity market prices and increases the absolute level of the Reach TDVs.
Renewable Portfolio Standard	Assumes California meets a 33% Renewable Electricity Standard (RES) by 2020 and continues to increase the penetration of renewables and other low-carbon generation through 2040 and beyond. This is expected to result in higher electricity rates beyond 2020 as reflected in the retail rate assumptions described above. We do not model a change in the market price shape of electricity due to renewables beyond 2020.

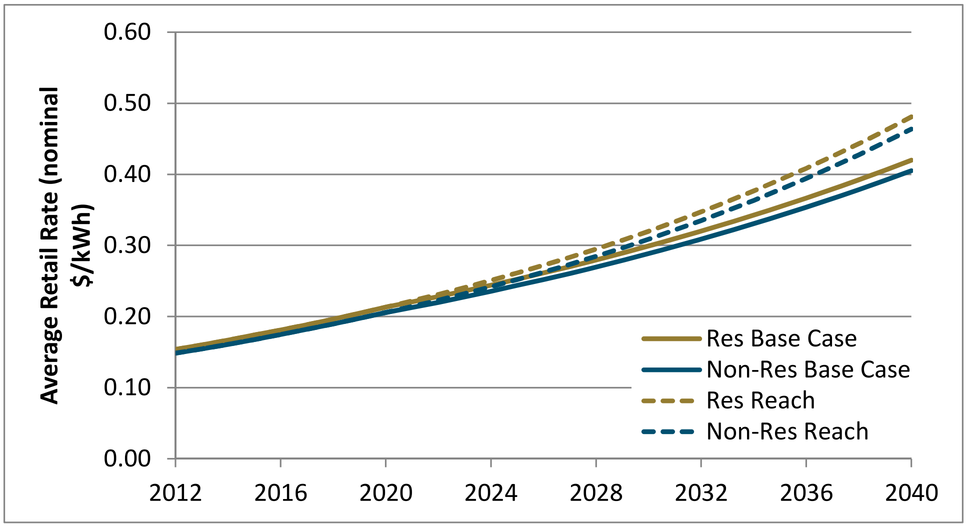
Other Policies (AB 32 Scoping Plan, Once-through cooling regulations)	Same as Base TDVs through 2020. Beyond 2020, there is an implicit assumption that a higher emphasis on energy efficiency, conservation and low-carbon generation will be necessary to achieve GHG reduction goals. This is expected to result in higher electricity rates beyond 2020, as reflected in the retail rate assumptions described above.
Real Discount Rate	3% real discount rate.

Below is a more detailed description of the thought process behind some of the key variables used to develop the Reach TDVs.

6.2.1 RETAIL RATE FORECAST AND INCREASING ENERGY COSTS BEYOND 2020

In the Reach TDVs, we assume that California continues to focus on reducing carbon beyond 2020, increasing the shares of energy efficiency, decarbonized electricity (through more renewables, nuclear, and/or CCS), and by electrifying many end-uses, including large shares of the transportation sector. Therefore, we reflect higher retail rate increases in the Reach TDVs input assumptions beyond 2020 compared to the Base TDVs.

Figure 18. Comparison of electric sector retail rate forecasts for Base Case and Reach TDVs.

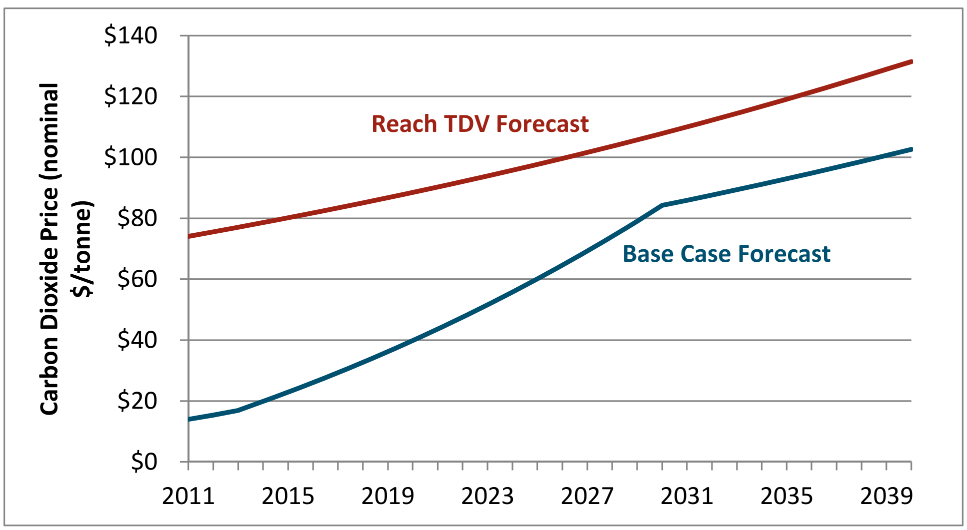


6.2.2 A SOCIETAL VALUE OF GREENHOUSE GAS REDUCTIONS

The Reach TDVs are reflective of a longer-term view of the value of greenhouse gas emission reductions. In order to capture this long-run view of the value of greenhouse gas mitigation, we change the value/cost of CO_2 in the input assumptions:

Carbon dioxide value versus market price: In the Base TDVs, the CO_2 price reflects an expected market price of CO_2 allowances, which does not necessarily reflect the societal value of CO_2 reductions. This is because the near term market price for CO_2 will be heavily influenced by the near term, lower cost means of reducing carbon dioxide as well as political and economic constraints, rather than the societal value of achieving GHG reductions. A longer-term, multi-generational view of CO_2 reductions reflects the fact that carbon dioxide released today will remain in the atmosphere for centuries,[6] and therefore we are valuing CO_2 savings at the cost future generations must pay to reduce CO_2, , not the short term market prices. Specifically, rather than the forecasted market price of a CO_2 allowance price in 2011 at $14/ton escalated over time to about $57/ton by 2040 (in real, $2010 terms), the Reach TDVs use the forecasted long-run marginal reduction cost of CO_2 across all years (2011 – 2040); around $74/ton in today's dollars.

Figure 19. Comparison of carbon dioxide price forecasts in the Base Case and Reach TDVs.



[6] Archer, David et al, "Atmospheric Lifetime of Fossil Fuel Carbon Dioxide," Annual Review of Earth and Planetary Sciences, Vol. 37: 117-134 (May 2009)

6.2.3 CALCULATING THE REACH TDV MULTIPLIERS

The absolute magnitude of the Base Case TDVs is determined by the net present value of the base case retail rate forecast. Under the Reach methodology, the magnitude of the TDVs is based on the net present value of the Reach retail rate forecast plus the incremental cost of carbon emissions, which are added on top of the retail rate adjusted for the Reach standard. Accordingly, the multipliers that translate from the Base Case to the Reach TDVs are calculated as the ratio of these two numbers. This approach is summarized in Table 12.

Table 12. Development of Reach multipliers for electricity

	Res (30 year)	Non-Res (15 year)	Non-Res (30 year)
Base Case TDVs			
Present Value "Current Practices" Retail Rate Forecast ($/kWh)	3.76	2.00	3.62
Load-Weighted Average Base Case TDV (kBtu/kWh)	21.68	22.49	23.53
Reach TDVs			
Present Value "Decarbonization" Retail Rate Forecast ($/kWh)	3.92	2.01	3.78
Lifecycle Emissions Externality Adder ($/kWh)	0.81	0.49	0.82
Load Weighted Average Reach TDV (kBtu/kWh)	27.30	28.19	29.89
Conversion from Base Case to Reach TDVs			
Reach Multiplier	**1.259**	**1.253**	**1.270**

To calculate multipliers for gas and propane, the same general approach is used. The only difference is that the same retail rate forecasts are used to determine the Base Case and Reach standards for gas and propane. This is because the drivers of the electricity retail rate escalation – the renewable development and advanced technologies forecast – are not as well defined for natural gas and propane consumption, so we do not change the retail gas and propane price forecasts under the Reach TDVs. The calculations of these multipliers are shown in Table 13 and Table 14.

Table 13. Development of Reach Multipliers for natural gas

	Res (30 year)	Non-Res (15 year)	Non-Res (30 year)
Base Case TDVs			
Present Value "Current Practices" Retail Rate Forecast ($/therm)	26.43	14.21	24.67
Load-Weighted Average Base Case TDV (kBtu/therm)	152.60	159.63	160.22
Reach TDVs			
Present Value "Decarbonization" Retail Rate Forecast ($/therm)	26.43	14.21	24.67
Lifecycle Emissions Externality Adder ($/therm)	8.74	5.33	8.74
Load Weighted Average Reach TDV (kBtu/therm)	203.09	219.47	217.00
Conversion from Base Case to Reach TDVs			
Reach Multiplier	**1.331**	**1.375**	**1.354**

Table 14. Development of Reach Multipliers for propane

	Res (30 year)	Non-Res (15 year)	Non-Res (30 year)
Base Case TDVs			
Present Value "Current Practices" Retail Rate Forecast ($/therm)	68.75	32.34	57.56
Load-Weighted Average Base Case TDV (kBtu/therm)	397.00	363.43	373.81
Reach TDVs			
Present Value "Decarbonization" Retail Rate Forecast ($/therm)	68.75	32.34	57.56
Lifecycle Emissions Externality Adder ($/therm)	10.46	6.37	10.46
Load Weighted Average Reach TDV (kBtu/therm)	457.41	435.04	441.75
Conversion from Base Case to Reach TDVs			
Reach Multiplier	**1.152**	**1.197**	**1.182**

Appendix A: Methodology for Creating Weather-Correlated Load Shapes for Use in the TDVs

6.3 Introduction

Hourly generation costs are a key input for developing the market price shape used in the Time Dependent Valuation (TDV) avoided costs for the Title 24 building standards. To develop a projection of hourly generation costs, we rely on the CEC's production simulation dispatch model (licensed from Ventyx Market Analytics). In the production simulation model runs, most of the data inputs developed for the CEC's 2009 report on the "Electricity System Implication of 33 Percent Renewables" are used. We use a model run for a 2012 year and a 2020 year, using the "High Wind" case developed in the 33 Percent Renewables Study. However, to ensure that the market price shapes produced by the CEC model are consistent with the statewide weather files used elsewhere in the Title 24 work, an important modification to the data inputs was required. E3 developed new load shapes which are correlated with the statewide typical weather year data files generated for the 2013 Title 24 proceeding. This means that during hot days in the typical weather files, the market prices also reflect higher electricity demands and thus higher energy costs.

This appendix describes the statistical methodology used for developing the weather-correlated load shapes, which are used in the production simulation dispatch model to generate hourly market price shapes for the 2013 TDVs.

6.4 Modeling considerations

Modeling a load shape which captures the relationship between historic hourly load and weather data should consider the following:[7]

- Hour-of-day effect. Hourly MW data exhibits an intra-day pattern. The lowest loads tend to occur around 04:00 and the highest 16:00.
- Day-of-week effect. Hourly MW data exhibits an inter-day pattern. Hourly loads tend to be low on weekend days and high on mid-week days.
- Holiday effect. Hourly loads on the day-before, day-of, and day-after a holiday tend be higher than on other days.
- Month-of-year effect. Hourly loads tend to be high in summer months and low in other months. But this may largely be driven by the monthly temperature pattern.
- Weather effect. Hourly loads move with weather. Hot (cold) days, especially after consecutive hot (cold) days, tend to have higher hourly loads than other days.

[7] Woo, C.K., P. Hanser and N. Toyama (1986) "Estimating Hourly Electric Load with Generalized Least Squares Procedures," The Energy Journal, 7:2, 153-170.

- Hourly load distribution. Hourly load data has a skewed distribution, with a long right tail. A logarithmic transformation of the load data yields a more symmetric distribution amenable to a regression-based approach to develop a typical weather year load shape.
- Peak loads. While a regression-based approach is useful for predicting hourly loads in a typical weather year, it produces a flatter shape than the one in real world. This is because regression-based predictions tend to gravitate towards the mean MW, rather than the maximum and minimum MW, which are, by definition, the two extreme ends of an hourly load distribution. However, a secondary regression is used to adjust values based on their ranks in a load duration curve.
- Load growth. The typical weather year load shape's maximum MW should match the system peak MW forecast. If the load modeling is done for normalized MW (= hourly MW / annual peak MW), the resulting prediction can then be scaled to match the forecast peak MW.

6.5 Regression-based approach

We use a regression-based approach to develop equations for predicting a normalized MW shape under the TMY weather. Illustrated with an SCE example, the approach has the following steps:

- Step 1: Use hourly observations in the 2003-2007 period (or 2000-2007 for some climate zones) with dry bulb temperature greater than or equal to 75^{o}F in one particular weather station (chosen to be Burbank for SCE) to estimate a linear regression whose dependent variable is $s = ln(S)$ where S = hourly MW / annual peak MW. This step aims to show how hourly MW varies with its fundamental drivers. The explanatory variables are the intercept; dummy variables for month-of-year, day-of-week, hour-of-day; dummy variables for day-before, day-of, and day-after a Federal holiday; and weather variables for some number of relevant stations (four are used in the case of SCE: Fresno, Riverside, Burbank and Long Beach).

- Each weather station has two associated sets of variables: one based on the dry bulb temperature, in order to capture effects based solely on temperature, and one based on dew point temperature, in order to capture the added demand for air conditioning on humid days.
- The weather variables are coincident cooling degree hours, coincident heating degree hours, weighted sum of lagged cooling degree days, and weighted sum of lagged heating degree days. The lagged heating and cooling degree days cover a three day span, and are used to represent cold and heat spells respectively.[8]

+ Step 2: Repeat Step 1 for the remaining hourly observations (less than 75°F). The regression resulting from Steps 1 and 2 can be written as:

$$s = \begin{cases} \beta_0 + \sum_{n=1}^{11} \beta_{m,n} m_n + \sum_{n=1}^{6} \beta_{d,n} d_n + \sum_{n=1}^{23} \beta_{h,n} h_n + \sum_{n=-1}^{1} \beta_{f,n} f_n + \sum_{n} \sum_{i=1}^{2} \sum_{j=1}^{4} \beta_{w,i,n,j} w_{n,i,j} + \varepsilon & if\ T_k \geq 75 \\ \eta_0 + \sum_{n=1}^{11} \eta_{m,n} m_n + \sum_{n=1}^{6} \eta_{d,n} d_n + \sum_{n=1}^{23} \eta_{h,n} h_n + \sum_{n=-1}^{1} \eta_{f,n} f_n + \sum_{n} \sum_{i=1}^{2} \sum_{j=1}^{4} \eta_{w,i,n,j} w_{n,i,j} + \varepsilon & if\ T_k < 75 \end{cases}$$

Here, β_0 and η_0 are the intercepts; m, d, and h are the month of year, day of week, and hour of day indicators; f is the federal holiday indicator; and w is the weather variable, which is summed over all weather stations (n), both dry bulb and dew point temperatures (i),

[8] Weight = 1/2 for the day before, 1/3 for two days before, and 1/6 for three days before.

and cooling and heating degree hours, as well as lagged cooling and heating degree days (j). T_k is the dry bulb temperature at a single weather station, chosen to be the most influential in the region, and ε is the error.

- Step 3: Use the regression results from Step 1 and Step 2 to make a preliminary prediction of an hourly normalized MW for a given weather condition: $S_P = \exp(s_P + v^2/2)$, where s_P = predicted value of $ln(S)$ and v^2 = variance of s_P.
- Step 4: Divide the S_P values from Step 3 into 20 bins, each containing 5% of the sample, based on each value's rank in a load duration curve. For example, bin "1" has S_P values below the 5-percentile, and bin "20" has values above the 95-percentile.
- Step 5: Run the actual vs. predicted regression:

$$S = \beta_0 + \sum_{n=1}^{19} \beta_{B,n} B_n + \beta_s s_p + \varepsilon$$

Here, β_0 is the intercept, B_n is the bin indicator, s_p is the normalized MW, and ε is the error. This step corrects for the fact that the preliminary prediction S_P may not match actual normalized MW, especially for bins near the bottom and bins near the top (e.g., $S_P > S$ in bin "1" and $S_P < S$ in "20").

- Step 6: Compute the final prediction S_F based on the regression result from Step 5. This value is limited to a maximum of 1 so that the annual peak MW value is not exceeded in the next step.
- Step 7: Make hourly MW prediction = S_F * annual peak MW.

6.6 Results

The results of this regression approach show very good prediction of actual loads. In the examples below, predicted and actual loads are compared for the sample of hourly data in 2007 for the SCE region. Figure 20 shows the predicted and actual load duration curves for 2007. Figure 21 shows the actual and predicted MW for the peak week in 2007. Since the predicted curves closely match the actual ones, the regression-based approach is useful for developing a TMY load shape.

Figure 20. 2007 Load Duration Curve for SCE

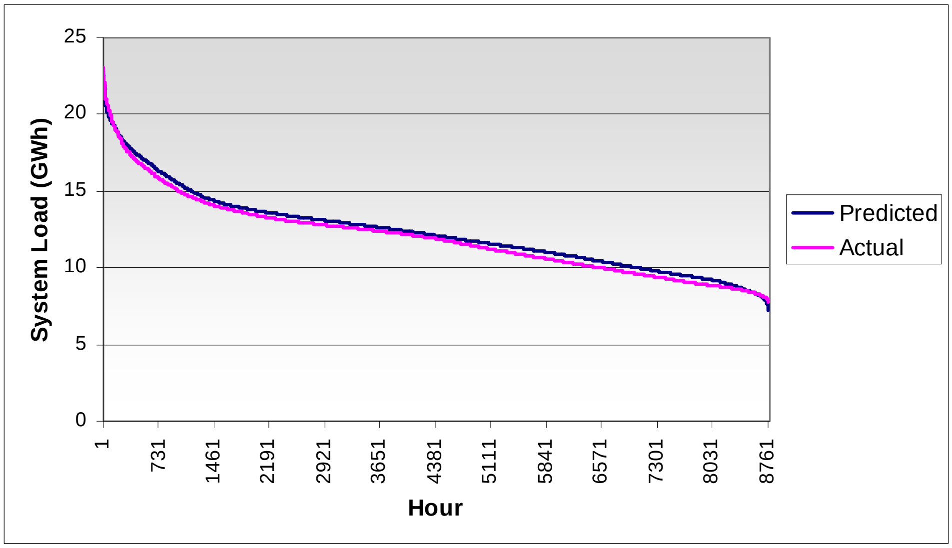
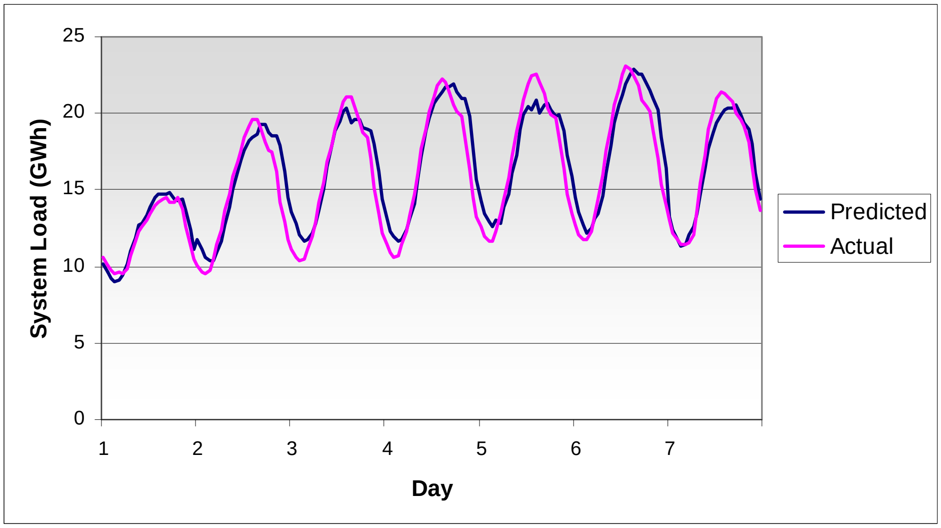


Figure 21. 2007 Peak Load Week for SCE



6.6.1 WEATHER STATIONS USED FOR LOAD SHAPE REGRESSIONS

The following table shows the utility service territory regions for which revised weather correlated load shapes were developed. The weather station data used in the statistical analysis are shown in the table as well. The weather stations were chosen based on their proximity to well-populated area within each region, and are shown in Table 15 below.

Table 15. Weather Stations Applied to Each Load Region in California

Load Region	Weather Stations Used in Analysis
Anaheim	LOS-ALAMITOS_722975
Burbank	BURBANK-GLENDALE_722880
CFE	IMPERIAL-BEACH_722909
Glendale	BURBANK-GLENDALE_722880
IID	IMPERIAL_747185
LADWP	LONG-BEACH_722970 BURBANK-GLENDALE_722880
MID	MODESTO_724926
NCPA	SACRAMENTO-METRO_724839
Pasadena	BURBANK-GLENDALE_722880
PG&E NP15	FRESNO_723890 SACRAMENTO-EXECUTIVE_724830 SAN-JOSE-INTL_724945 SAN-FRANCISCO-INTL_724940 UKIAH_725905
PG&E ZP26	FRESNO_723890 BAKERSFIELD_723840
Redding	REDDING_725920
Riverside	RIVERSIDE_722869
SCE	FRESNO_723890 LONG-BEACH_722970 RIVERSIDE_722869 BURBANK-GLENDALE_722880
SDG&E	SAN-DIEGO-LINDBERGH_722900 SAN-DIEGO-MONTGOMER_722903 SAN-DIEGO-GILLESPIE_722907
SMUD	SACRAMENTO-EXECUTIVE_724830
SVP	SAN JOSE-INTL_724945
TID	MODESTO_724926

Appendix B. Data Input Updates between 2008 and 2013 TDVs

Table 16. Comparison of 2008 TDV and 2013 TDV Inputs

	2008 Title 24 TDV factors	2013 Title 24 TDV factors
Calendar year of TDVs	1991	2009
Dollar year of TDV NPV costs	2008	2011
Market price shape	CEC production simulation dispatch model, using 'business-as-usual' assumptions circa 2005. The energy component of the TDV values is not explicitly correlated with weather files.	CEC production simulation dispatch model for years 2012 and 2020. Price shapes are correlated with the climate zone weather files. The 2020 runs assume statewide achievements of the 33% Renewable Electricity Standard, so the underlying energy price reflects a different generation mix.

	2008 Title 24 TDV factors	2013 Title 24 TDV factors
Natural gas price forecast	NYMEX market price forecast for natural gas based on the average forward prices from 2005, transitioning to a long-run 'fundamentals' forecast developed by the CEC in 2005.	NYMEX forward prices from 2010, forecast prices for 12 years. Year 13 is a trend of the last five years of NYMEX data. Years 14 through 25 are forecast by applying the price changes from the 2009 Market Price Referent (MPR) fundamental forecast to the year 13 price.
Carbon price forecast	Carbon price trajectory developed in 2004.	Same price forecast as CPUC Market Price Referent, based on "mid-price" trajectory from 2008 Synapse Consulting report.
T&D Avoided Costs	General Rate Case filings from 1999 to 2001 for PG&E, SCE & SDG&E. Costs allocated to hours using the same methodology as the TDV methodology. Costs are allocated based on CEC climate zone weather data used for the 2008 building simulations.	General Rate Case filings from 2009 for PG&E, SCE & SDG&E, then the statewide sales weighted average is used for each climate zone. Also, 2013 TDV uses a higher loss factor for distribution capacity savings, the 2008 number was too low. Costs allocated based on updated CEC typical weather data developed in 2010.
Ancillary Services	Average total ancillary services cost factors of 2.8% of the energy market cost.	Updated to 2010 CAISO MRTU market levels. The new market design has substantially reduced ancillary service costs, and therefore avoided costs. Load reduction (e.g. efficiency) is only credited with spinning and non-spinning reserves.